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Transient Stability

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8.1 Introduction

As discussed in [Chapter 7](#), power system stability was recognized as a problem as far back as the 1920s at which time the characteristic structure of systems consisted of remote power plants feeding load centers over long distances. These early stability problems, often a result of insufficient synchronizing torque, were the first emergence of transient instability. As defined in the previous chapter, *transient stability* is the ability of a power system to remain in synchronism when subjected to large transient disturbances. These disturbances may include faults on transmission elements, loss of load, loss of generation, or loss of system components such as transformers or transmission lines.

Although many different forms of power system stability have emerged and become problematic in recent years, transient stability still remains a basic and important consideration in power system design and operation. While it is true that the operation of many power systems are limited by phenomena such as voltage stability or small-signal stability, most systems are prone to transient instability under certain conditions or contingencies and hence the understanding and analysis of transient stability remain fundamental issues. Also, we shall see later in this chapter that transient instability can occur in a very short time-frame (a few seconds) leaving no time for operator intervention to mitigate problems; it is therefore essential to deal with the problem in the design stage or severe operating restrictions may result.

In this chapter we discuss the basic principles of transient stability, methods of analysis, control and enhancement, and practical aspects of its influence on power system design and operation.

8.2 Basic Theory of Transient Stability

Most power system engineers are familiar with plots of generator rotor angle (δ) versus time as shown in [Fig. 8.1](#). These “swing curves” plotted for a generator subjected to a particular system disturbance show whether a generator rotor angle recovers and oscillates around a new equilibrium point as in trace “a” or

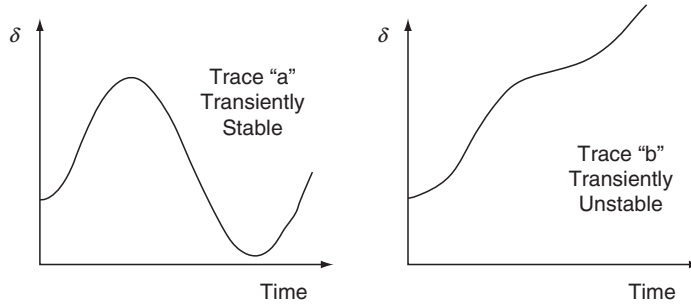


FIGURE 8.1 Plots showing the trajectory of generator rotor angle through time for transient stable and transiently unstable cases.

whether it increases aperiodically such as in trace “b.” The former case is deemed to be transiently stable, and the latter case transiently unstable. What factors determine whether a machine will be stable or unstable? How can the stability of large power systems be analyzed? If a case is unstable, what can be done to enhance its stability? These are some of the questions we seek to answer in this section.

Two concepts are essential in understanding transient stability: (i) the swing equation and (ii) the power–angle relationship. These can be used together to describe the equal area criterion, a simple graphical approach to assessing transient stability [1–3].

8.2.1 Swing Equation

In a synchronous machine, the prime mover exerts a mechanical torque T_m on the shaft of the machine and the machine produces an electromagnetic torque T_e . If, as a result of a disturbance, the mechanical torque is greater than the electromagnetic torque, an accelerating torque T_a exists and is given by

$$T_a = T_m - T_e \quad (8.1)$$

This ignores the other torques caused by friction, core loss, and windage in the machine. T_a has the effect of accelerating the machine, which has an inertia J ($\text{kg} \cdot \text{m}^2$) made up of the inertia of the generator and the prime mover and therefore

$$J \frac{d\omega_m}{dt} = T_a = T_m - T_e \quad (8.2)$$

where t is time in seconds and ω_m is the angular velocity of the machine rotor in mechanical rad/s. It is common practice to express this equation in terms of the inertia constant H of the machine. If ω_{0m} is the rated angular velocity in mechanical rad/s, J can be written as

$$J = \frac{2H}{\omega_{0m}^2} VA_{\text{base}} \quad (8.3)$$

Therefore

$$\frac{2H}{\omega_{0m}^2} VA_{\text{base}} \frac{d\omega_m}{dt} = T_m - T_e \quad (8.4)$$

And now, if ω_r denotes the angular velocity of the rotor (rad/s) and ω_0 its rated value, the equation can be written as

$$2H \frac{d\bar{\omega}_r}{dt} = \bar{T}_m - \bar{T}_e \quad (8.5)$$

Finally it can be shown that

$$\frac{d\bar{\omega}_r}{dt} = \frac{d^2\delta}{\omega_0 dt^2} \quad (8.6)$$

where δ is the angular position of the rotor (elec. rad/s) with respect to a synchronously rotating reference frame.

Combining Eqs. (8.5) and (8.6) results in the *swing equation* [Eq. (8.7)], so-called because it describes the swings of the rotor angle δ during disturbances:

$$\frac{2H}{\omega_0} \frac{d^2\delta}{dt^2} = \bar{T}_m - \bar{T}_e \quad (8.7)$$

An additional term $(-K_D \Delta\bar{\omega}_r)$ may be added to the right-hand side of Eq. (8.7) to account for a component of damping torque not included explicitly in $\bar{T}_e$.

For a system to be *transiently stable* during a disturbance, it is necessary for the rotor angle (as its behavior is described by the swing equation) to oscillate around an equilibrium point. If the rotor angle increases indefinitely, the machine is said to be *transiently unstable* as the machine continues to accelerate and does not reach a new state of equilibrium. In multimachine systems, such a machine will “pull out of step” and lose synchronism with the rest of the machines.

8.2.2 Power–Angle Relationship

Consider a simple model of a single generator connected to an infinite bus through a transmission system as shown in Fig. 8.2. The model can be reduced as shown by replacing the generator with a constant voltage behind a transient reactance (classical model). It is well known that there is a maximum power that can be transmitted to the infinite bus in such a network. The relationship between the electrical power of the generator P_e and the rotor angle of the machine δ is given by

$$P_e = \frac{E' E_B}{X_T} \sin \delta = P_{\max} \sin \delta \quad (8.8)$$

where

$$P_{\max} = \frac{E' E_B}{X_T} \quad (8.9)$$

Equation (8.8) can be shown graphically as Fig. 8.3 from which it can be seen that as the power initially increases δ increases until reaching 90° when P_e reaches its maximum. Beyond $\delta = 90^\circ$, the power decreases until at $\delta = 180^\circ$, $P_e = 0$. This is the so-called power–angle relationship and describes the transmitted power as a function of rotor angle. It is clear from Eq. (8.9) that the maximum power is a function of the voltages of the generator and infinite bus, and more importantly, a function of the transmission system reactance; the larger the reactance (for example the longer or weaker the transmission circuits), the lower the maximum power.

Figure 8.3 shows that for a given input power to the generator P_{m1} , the electrical output power is P_e (equal to P_m) and the corresponding rotor angle is δ_a . As the mechanical power is increased to P_{m2} , the rotor angle advances to δ_b . Figure 8.4 shows the case with one of the transmission lines removed causing

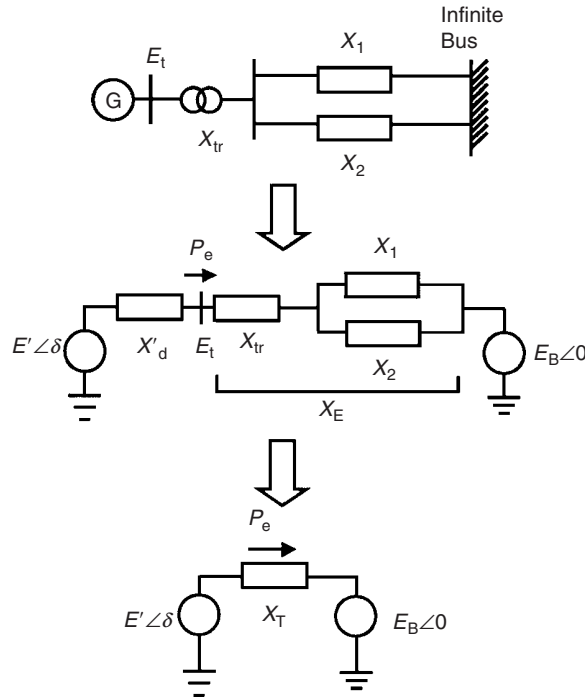


FIGURE 8.2 Simple model of a generator connected to an infinite bus.

an increase in X_T and a reduction $P_{\max}$. It can be seen that for the same mechanical input (P_{m1}), the situation with one line removed causes an increase in rotor angle to δ_c .

8.2.3 Equal Area Criterion

By combining the dynamic behavior of the generator as defined by the swing equation, with the power-angle relationship, it is possible to illustrate the concept of transient stability using the *equal area criterion*.

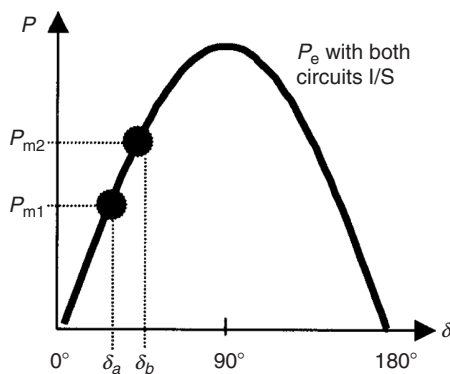


FIGURE 8.3 Power-angle relationship for case with both circuits in-service.

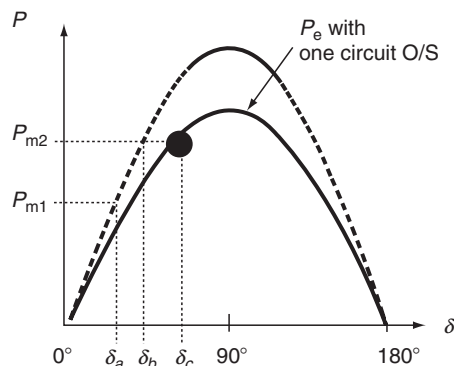


FIGURE 8.4 Power-angle relationship for case with one circuit out-of-service.

Consider Fig. 8.5 in which a step change is applied to the mechanical input of the generator. At the initial power P_{m0} , $\delta = \delta_0$ and the system is at operating point “a.” As the power is increased in a step to P_{m1} (accelerating power = $P_{m1} - P_e$), the rotor cannot accelerate instantaneously, but traces the curve up to point “b” at which time $P_e = P_{m1}$ and the accelerating power is zero. However, the rotor speed is greater than the synchronous speed and the angle continues to increase. Beyond b, $P_e > P_m$ and the rotor decelerates until reaching a maximum $\delta_{\max}$ at which point the rotor angle starts to return toward b.

As we will see, for a single-machine infinite bus system, it is not necessary to plot the swing curve to determine if the rotor angle of the machine increases indefinitely, or if it oscillates around an equilibrium point. The equal area criterion allows stability to be determined using graphical means. While this method is not generally applicable to multimachine systems, it is a valuable learning aid.

Starting with the swing equation as given by Eq. (8.7) and interchanging per unit power for torque

$$\frac{d^2\delta}{dt^2} = \frac{\omega_0}{2H} (P_m - P_e) \quad (8.10)$$

Multiplying both sides by $2\delta/dt$ and integrating gives

$$\left[\frac{d\delta}{dt}\right]^2 = \int_{\delta_0}^{\delta} \frac{\omega_0(P_m - P_e)}{H} d\delta \quad \text{or} \quad \frac{d\delta}{dt} = \sqrt{\int_{\delta_0}^{\delta} \frac{\omega_0(P_m - P_e)}{H} d\delta} \quad (8.11)$$

δ_0 represents the rotor angle when the machine is operating synchronously prior to any disturbance. It is clear that for the system to be stable, δ must increase, reach a maximum ($\delta_{\max}$) and then change direction as the rotor returns to complete an oscillation. This means that $d\delta/dt$ (which is initially zero) changes during the disturbance, but must, at a time corresponding to $\delta_{\max}$, become zero again. Therefore, as a stability criterion

$$\int_{\delta_0}^{\delta} \frac{\omega_0}{H} (P_m - P_e) d\delta = 0 \quad (8.12)$$

This implies that the area under the function $P_m - P_e$ plotted against δ must be zero for a stable system, which requires Area 1 to be equal to Area 2. Area 1 represents the energy gained by the rotor during acceleration and Area 2 represents energy lost during deceleration.

Figures 8.6 and 8.7 show the rotor response (defined by the swing equation) superimposed on the power–angle curve for a stable case and an unstable case, respectively. In both cases, a three-phase fault is applied to the system given in Fig. 8.2. The only difference in the two cases is that the fault-clearing time has been increased for the unstable case. The arrows show the trace of the path followed by the rotor angle in terms of the swing equation and power–angle relationship. It can be seen that for the stable case, the energy gained during rotor acceleration is equal to the energy dissipated during deceleration

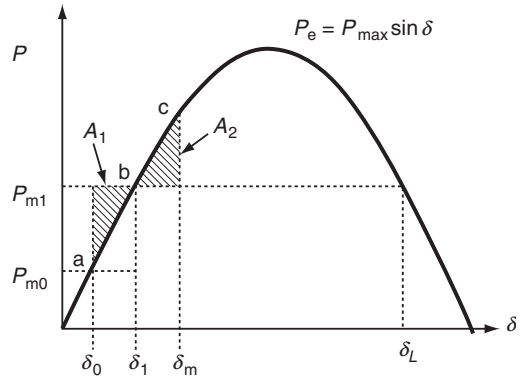


FIGURE 8.5 Power–angle curve showing the areas defined in the Equal Area Criterion. Plot shows the result of a step change in mechanical power.

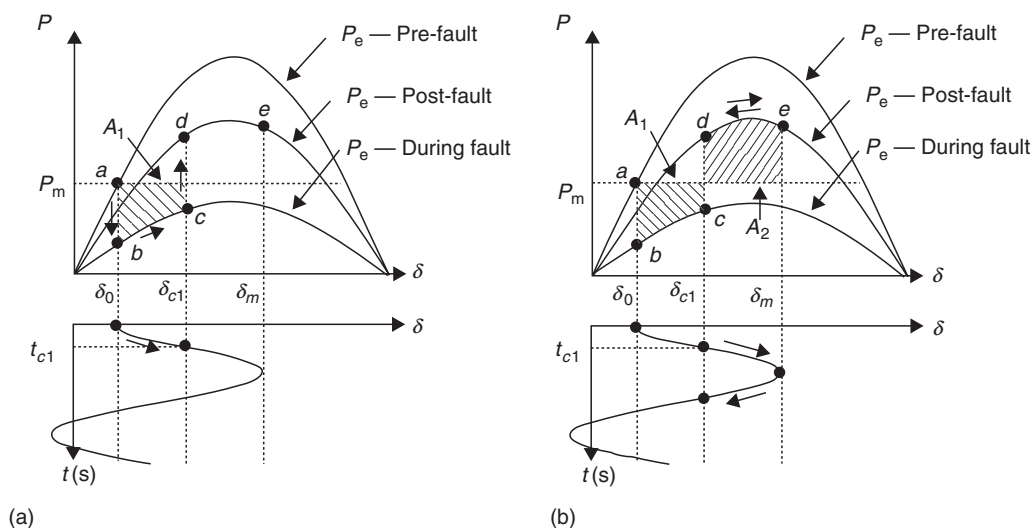


FIGURE 8.6 Rotor response (defined by the swing equation) superimposed on the power–angle curve for a stable case.

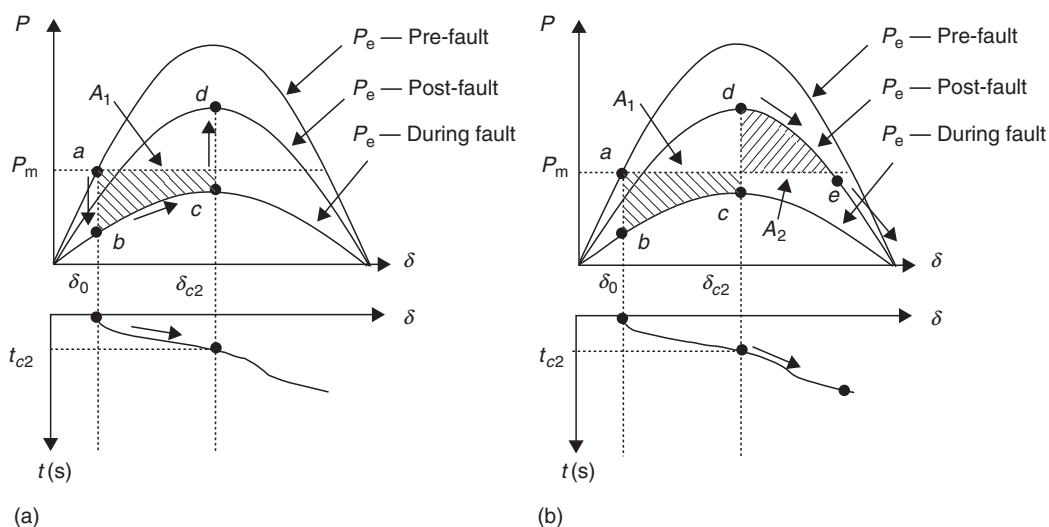


FIGURE 8.7 Rotor response (defined by the swing equation) superimposed on the power–angle curve for an unstable case.

($A_1 = A_2$) and the rotor angle reaches a maximum and recovers. In the unstable case, however, it can be seen that the energy gained during acceleration is greater than that dissipated during deceleration (since the fault is applied for a longer duration) meaning that $A_1 > A_2$ and the rotor continues to advance and does not recover.

8.3 Methods of Analysis of Transient Stability

8.3.1 Modeling

The basic concepts of transient stability presented above are based on highly simplified models. Practical power systems consist of large numbers of generators, transmission circuits, and loads.

For stability assessment, the power system is normally represented using a positive sequence model. The network is represented by a traditional positive sequence powerflow model, which defines the transmission topology, line reactances, connected loads and generation, and predisturbance voltage profile.

Generators can be represented with various levels of detail, selected based on such factors as length of simulation, severity of disturbance, and accuracy required. The most basic model for synchronous generators consists of a constant internal voltage behind a constant transient reactance, and the rotating inertia constant (H). This is the so-called classical representation that neglects a number of characteristics: the action of voltage regulators, variation of field flux linkage, the impact of the machine physical construction on the transient reactances for the direct and quadrature axis, the details of the prime mover or load, and saturation of the magnetic core iron. Historically, classical modeling was used to reduce computational burden associated with more detailed modeling, which is not generally a concern with today's simulation software and computer hardware. However, it is still often used for machines that are very remote from a disturbance (particularly in very large system models) and where more detailed model data is not available.

In general, synchronous machines are represented using detailed models, which capture the effects neglected in the classical model including the influence of generator construction (damper windings, saturation, etc.), generator controls (excitation systems including power system stabilizers, etc.), the prime mover dynamics, and the mechanical load. Loads, which are most commonly represented as static voltage and frequency dependent components, may also be represented in detail by dynamic models that capture their speed torque characteristics and connected loads. There are a myriad of other devices, such as HVDC lines and controls and static Var devices, which may require detailed representation. Finally, system protections are often represented. Models may also be included for line protections (such as mho distance relays), out-of-step protections, loss of excitation protections, or special protection schemes.

Although power system models may be extremely large, representing thousands of generators and other devices producing systems with tens-of-thousands of system states, efficient numerical methods combined with modern computing power have made time-domain simulation readily available in many commercially available computer programs. It is also important to note that the time frame in which transient instability occurs is usually in the range of 1–5 s, so that simulation times need not be excessively long.

8.3.2 Analytical Methods

To accurately assess the system response following disturbances, detailed models are required for all critical elements. The complete mathematical model for the power system consists of a large number of algebraic and differential equations, including

- Generators stator algebraic equations
- Generator rotor circuit differential equations
- Swing equations
- Excitation system differential equations
- Prime mover and governing system differential equations
- Transmission network algebraic equations
- Load algebraic and differential equations

While considerable work has been done on *direct methods* of stability analysis in which stability is determined without explicitly solving the system differential equations (see [Chapter 11](#)), the most practical and flexible method of transient stability analysis is *time-domain simulation* using step-by-step numerical integration of the nonlinear differential equations. A variety of numerical integration methods are used, including *explicit* methods (such as Euler and Runge–Kutta methods) and *implicit* methods (such as the trapezoidal method). The selection of the method to be used depends largely on

the stiffness of the system being analyzed. In systems in which time-steps are limited by numerical stability rather than accuracy, implicit methods are generally better suited than the explicit methods.

8.3.3 Simulation Studies

Modern simulation tools offer sophisticated modeling capabilities and advanced numerical solution methods. Although each simulation tool differs somewhat, the basic requirements and functions are the same [4].

8.3.3.1 Input Data

1. Powerflow: Defines system topology and initial operating state.
2. Dynamic data: Includes model types and associated parameters for generators, motors, protections, and other dynamic devices and their controls.
3. Program control data: Specifies such items as the type of numerical integration to use and time-step.
4. Switching data: Includes the details of the disturbance to be applied. This includes the time at which the fault is applied, where the fault is applied, the type of fault and its fault impedance if required, the duration of the fault, the elements lost as a result of the fault, and the total length of the simulation.
5. System monitoring data: This specifies the quantities that are to be monitored (output) during the simulation. In general, it is not practical to monitor all quantities because system models are large, and recording all voltages, angles, flows, generator outputs, etc., at each integration time-step would create an enormous volume. Therefore, it is a common practice to define a limited set of parameters to be recorded.

8.3.3.2 Output Data

1. Simulation log: This contains a listing of the actions that occurred during the simulation. It includes a recording of the actions taken to apply the disturbance, and reports on any operation of protections or controls, or any numerical difficulty encountered.
2. Results output: This is an ASCII or binary file that contains the recording of each monitored variable over the duration of the simulation. These results are examined, usually through a graphical plotting, to determine if the system remained stable and to assess the details of the dynamic behavior of the system.

8.4 Factors Influencing Transient Stability

Many factors affect the transient stability of a generator in a practical power system. From the small system analyzed above, the following factors can be identified:

- The post-disturbance system reactance as seen from the generator. The weaker the post-disturbance system, the lower the $P_{\max}$ will be.
- The duration of the fault-clearing time. The longer the fault is applied, the longer the rotor will be accelerated and the more kinetic energy will be gained. The more energy that is gained during acceleration, the more difficult it is to dissipate it during deceleration.
- The inertia of the generator. The higher the inertia, the slower the rate of change of angle and the lesser the kinetic energy gained during the fault.
- The generator internal voltage (determined by excitation system) and infinite bus voltage (system voltage). The lower these voltages, the lower the $P_{\max}$ will be.
- The generator loading before the disturbance. The higher the loading, the closer the unit will be to $P_{\max}$, which means that during acceleration, it is more likely to become unstable.
- The generator internal reactance. The lower the reactance, the higher the peak power and the lower the initial rotor angle.
- The generator output during the fault. This is a function of faults location and type of fault.

8.5 Transient Stability Considerations in System Design

As outlined in [Section 8.1](#), transient stability is an important consideration that must be dealt with during the design of power systems. In the design process, time-domain simulations are conducted to assess the stability of the system under various conditions and when subjected to various disturbances. Since it is not practical to design a system to be stable under all possible disturbances, design criteria specify the disturbances for which the system must be designed to be stable. The criteria disturbances generally consist of the more statistically probable events, which could cause the loss of any system element and typically include three-phase faults cleared in normal time and line-to-ground faults with delayed clearing due to breaker failure. In most cases, stability is assessed for the loss of one element (such as a transformer or transmission circuit) with possibly one element out-of-service in the predisturbance system. In system design, therefore, a wide number of disturbances are assessed and if the system is found to be unstable (or marginally stable) a variety of actions can be taken to improve stability [1]. These include the following:

- *Reduction of transmission system reactance:* This can be achieved by adding additional parallel transmission circuits, providing series compensation on existing circuits, and by using transformers with lower leakage reactances.
- *High-speed fault clearing:* In general, two-cycle breakers are used in locations where faults must be removed quickly to maintain stability. As the speed of fault clearing decreases, so does the amount of kinetic energy gained by the generators during the fault.
- *Dynamic braking:* Shunt resistors can be switched in following a fault to provide an artificial electrical load. This increases the electrical output of the machines and reduces the rotor acceleration.
- *Regulate shunt compensation:* By maintaining system voltages around the power system, the flow of synchronizing power between generators is improved.
- *Reactor switching:* The internal voltages of generators, and therefore stability, can be increased by connected shunt reactors.
- *Single pole switching and reclosing:* Most power system faults are of the single-line-to-ground type. However, in most schemes, this type of fault will trip all three phases. If single pole switching is used, only the faulted phase is removed, and power can flow on the remaining two phases thereby greatly reducing the impact of the disturbance. The single-phase is reclosed after the fault is cleared and the fault medium is deionized.
- *Steam turbine fast-valving:* Steam valves are rapidly closed and opened to reduce the generator accelerating power in response to a disturbance.
- *Generator tripping:* Perhaps one of the oldest and most common methods of improving transient stability, this approach disconnects selected generators in response to a disturbance that has the effect of reducing the power, which is required to be transferred over critical transmission interfaces.
- *High-speed excitation systems:* As illustrated by the simple examples presented earlier, increasing the internal voltage of a generator has the effect of proving transient stability. This can be achieved by fast acting excitation systems, which can rapidly boost field voltage in response to disturbances.
- *Special excitation system controls:* It is possible to design special excitation systems that can use discontinuous controls to provide special field boosting during the transient period thereby improving stability.
- *Special control of HVDC links:* The DC power on HVDC links can be rapidly ramped up or down to assist in maintaining generation/load imbalances caused by disturbances. The effect is similar to generation or load tripping.
- *Controlled system separation and load shedding:* Generally considered a last resort, it is feasible to design system controls that can respond to separate, or island, a power system into areas with

balanced generation and load. Some load shedding or generation tripping may also be required in selected islands. In the event of a disturbance, instability can be prevented from propagating and affecting large areas by partitioning the system in this manner. If instability primarily results in generation loss, load shedding alone may be sufficient to control the system.

8.6 Transient Stability Considerations in System Operation

While it is true that power systems are designed to be transiently stable, and many of the methods described above may be used to achieve this goal, in actual practice, systems may be prone to being unstable. This is largely due to uncertainties related to assumptions made during the design process. These uncertainties result from a number of sources including:

- *Load and generation forecast:* The design process must use forecast information about the amount, distribution, and characteristics of the connected loads as well as the location and amount of connected generation. These all have a great deal of uncertainty. If the actual system load is higher than planned, the generation output will be higher, the system will be more stressed, and the transient stability limit may be significantly lower.
- *System topology:* Design studies generally assume all elements in service, or perhaps up to two elements out-of-service. In actual systems, there are usually many elements out-of-service at any one time due to forced outages (failures) or system maintenance. Clearly, these outages can seriously weaken the system and make it less transiently stable.
- *Dynamic modeling:* All models used for power system simulation, even the most advanced, contain approximations out of practical necessity.
- *Dynamic data:* The results of time-domain simulations depend heavily on the data used to represent the models for generators and the associated controls. In many cases, this data is not known (typical data is assumed) or is in error (either because it has not been derived from field measurements or due to changes that have been made in the actual system controls that have not been reflected in the data).
- *Device operation:* In the design process it is assumed that controls and protection will operate as designed. In the actual system, relays, breakers, and other controls may fail or operate improperly.

To deal with these uncertainties in actual system operation, safety margins are used. Operational (short-term) time-domain simulations are conducted using a system model, which is more accurate (by accounting for elements out on maintenance, improved short-term load forecast, etc.) than the design model. Transient *stability limits* are computed using these models. The limits are generally in terms of maximum flows allowable over critical interfaces, or maximum generation output allowable from critical generating sources. Safety *margins* are then applied to these computed limits. This means that actual system operation is restricted to levels (interface flows or generation) below the stability limit by an amount equal to a defined safety margin. In general, the margin is expressed in terms of a percentage of the critical flow or generation output. For example, an operation procedure might be to set the *operating limit* at a flow level 10% below the stability limit.

A growing trend in system operations is to perform transient stability assessment *on-line* in *near-real-time*. In this approach, the powerflow defining the system topology and the initial operating state is derived, at regular intervals, from actual system measurements via the energy management system (EMS) using state-estimation methods. The derived powerflow together with other data required for transient stability analysis is passed to transient stability software residing on dedicated computers and the computations required to assess all credible contingencies are performed within a specified cycle time. Using advanced analytical methods and high-end computer hardware, it is currently possible to assess the transient stability of vary large systems, for a large number of contingencies, in cycle times typically ranging from 5 to 30 min. Since this on-line approach uses information derived directly from

the actual power system, it eliminates a number of the uncertainties associated with load forecasting, generation forecasting, and prediction of system topology, thereby leading to more accurate and meaningful stability assessment.

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